UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2005

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**39-1715850**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, TX 77002
(Address of principal executive offices and zip code)

(713) 821-2000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒ No ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The Registrant had 46,802,634 Class A common units outstanding as of October 28, 2005.

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In this report, unless the context requires otherwise, references to "we", "us", "our", or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "would," or "will" or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$1,809.6	$1,004.8	$4,392.4	$2,957.0
Operating expenses				
Cost of natural gas (Note 4)	1,659.8	824.5	3,882.4	2,443.8
Operating and administrative	82.4	67.3	237.2	197.8
Power	19.0	19.7	53.2	54.0
Depreciation and amortization (Note 6)	36.5	31.7	103.9	89.2
	1,797.7	943.2	4,276.7	2,784.8
Operating income	11.9	61.6	115.7	172.2
Interest expense	(28.4)	(22.2)	(79.6)	(65.8)
Rate refunds	—	(12.0)	—	(12.0)
Other income	2.1	0.2	3.4	2.2
Net income (loss)	$ (14.4)	$ 27.6	$ 39.5	$ 96.6
Net income (loss) allocable to common and i-units	$ (19.5)	$ 22.1	$ 22.6	$ 80.1
Net income (loss) per common and i-unit (basic and diluted) (Note 3)	$ (0.32)	$ 0.39	$ 0.37	$ 1.45
Weighted average units outstanding	62.1	55.7	61.5	55.1

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30, 2005	Three months ended September 30, 2004	Nine months ended September 30, 2005	Nine months ended September 30, 2004
	(unaudited; in millions)			
Net income (loss)	$ (14.4)	$ 27.6	$ 39.5	$ 96.6
Unrealized loss on derivative financial instruments (Note 4)	(138.4)	(47.7)	(224.1)	(72.6)
Comprehensive (loss) income	$(152.8)	$(20.1)	$(184.6)	$ 24.0

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine months ended September 30, 2005	2004
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 39.5	$ 96.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	103.9	89.2
Derivative fair value loss (Note 4)	69.4	1.4
Environmental liabilities	—	(2.0)
Other	(0.1)	0.2
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	(13.1)	(30.1)
Due from General Partner and affiliates	(6.2)	7.2
Accrued receivables	(338.8)	(39.7)
Inventory	(66.2)	(49.0)
Current and long-term other assets	(3.3)	12.3
Due to General Partner and affiliates	13.5	4.7
Accounts payable and other	(2.0)	55.1
Accrued purchases	385.5	48.5
Interest payable	24.5	25.5
Property and other taxes payable	1.6	6.0
Net cash provided by operating activities	208.2	225.9
Cash used in investing activities		
Additions to property, plant and equipment	(261.9)	(174.6)
Changes in construction payables	3.3	0.8
Asset acquisitions, net of cash acquired (Note 2)	(186.4)	(139.9)
Other	2.7	0.3
Net cash used in investing activities	(442.3)	(313.4)
Cash provided by financing activities		
Proceeds from unit issuances, net (Note 8)	127.5	194.2
Distributions to partners (Note 8)	(157.3)	(140.4)
Borrowings under debt agreements	2,851.0	2,042.8
Repayments of debt	(2,571.0)	(1,979.5)
Other	(1.0)	—
Net cash provided by financing activities	249.2	117.1
Net increase in cash and cash equivalents	15.1	29.6
Cash and cash equivalents at beginning of year	78.3	64.4
Cash and cash equivalents at end of period	$ 93.4	$ 94.0

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2005	December 31, 2004
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 93.4	$ 78.3
Receivables, trade and other, net of allowance for doubtful accounts of $4.3 in 2005 and $4.0 in 2004	84.8	71.7
Due from General Partner and affiliates	13.9	7.7
Accrued receivables	717.0	378.2
Inventory	147.6	84.5
Other current assets	22.8	13.4
	1,079.5	633.8
Property, plant and equipment, net (Note 6)	3,111.5	2,778.0
Other assets, net	26.2	27.7
Goodwill	258.2	257.2
Intangibles, net	85.6	74.0
	$4,561.0	$3,770.7
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 23.4	$ 9.9
Accounts payable and other (Note 5)	271.7	136.4
Accrued purchases	736.9	351.4
Interest payable	29.6	12.3
Property and other taxes payable	24.9	23.3
Current maturities of long-term debt	31.0	31.0
	1,117.5	564.3
Long-term debt (Note 7)	1,838.4	1,559.4
Loans from General Partner and affiliates	149.3	142.1
Environmental liabilities (Note 8)	5.4	5.3
Other long-term liabilities (Note 4)	267.0	101.7
	3,377.6	2,372.8
Commitments and contingencies (Note 8)		
Partners' capital		
Class A common units (Units issued—46,802,634 in 2005 and 44,296,134 in 2004)	1,025.1	1,021.6
Class B common units (Units issued—3,912,750 in 2005 and 2004)	62.8	66.7
i-units (Units issued—11,497,555 in 2005 and 10,902,409 in 2004)	408.9	399.4
General Partner	31.5	31.0
Accumulated other comprehensive loss (Note 4)	(344.9)	(120.8)
	1,183.4	1,397.9
	$4,561.0	$3,770.7

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the financial position as of September 30, 2005 and December 31, 2004; and the results of operations for the three and nine month periods ended September 30, 2005 and 2004; and cash flows for the nine month periods ended September 30, 2005 and 2004. The results of operations for the three and nine month periods ended September 30, 2005, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the natural gas business, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. In addition, prior period information presented in these consolidated financial statements includes reclassifications that were made to conform to the current period presentation. These reclassifications have no effect on previously reported net income or partners' capital. The interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

2. ACQUISITIONS

North Texas Natural Gas System

In January 2005, we acquired natural gas gathering and processing assets for $164.6 million in cash, including transaction costs of $0.5 million. We funded the acquisition with borrowings under our existing credit facilities. The assets acquired serve the Fort Worth Basin, which is mature, but experiencing minimal production decline rates and include:

- 2,200 miles of gas gathering pipelines; and
- four processing plants with aggregate processing capacity of 121 million cubic feet of natural gas per day ("MMcf/d").

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the natural gas and then selling the natural gas liquids ("NGL" or "NGLs") and residue natural gas streams. The assets and results of operations are included in our Natural Gas segment from the date of acquisition.

The purchase price and the allocation to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:	
Cash paid, including transaction costs	$164.6
Allocation of purchase price:	
Property, plant and equipment, including construction in progress	151.6
Intangibles, including contracts	14.3
Current liabilities	(0.9)
Contingent liabilities	(0.4)
Total	$164.6

Other Acquisitions

In June 2005, we acquired for $20.1 million in cash, a natural gas pipeline and related facilities consisting of 92 miles of a 20-inch diameter pipeline that extends from Pampa, Texas into western Oklahoma and has interconnects with our Anadarko system. We integrated this pipeline into our existing Anadarko system and have included the assets and operating results in our Natural Gas segment from the date of acquisition. The purchase price for this acquisition was allocated to property, plant and equipment for $19.1 million and goodwill for $1.0 million. We have also acquired other gathering and processing assets during 2005 for cash totaling approximately $1.7 million.

3. NET INCOME PER COMMON AND i-UNIT

Net income per common and i-unit is computed by dividing net income, after deduction of Enbridge Energy Company, Inc.'s (the "General Partner") allocation, by the weighted average number of Class A and Class B common units and i-units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. We have no dilutive securities. Net income per common and i-unit was determined as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
	(in millions, except per unit amounts)			
Net income (loss)	$(14.4)	$27.6	$ 39.5	$ 96.6
Allocations to the General Partner:				
Net (income) loss allocated to General Partner	0.3	(0.5)	(0.8)	(1.9)
Incentive distributions to General Partner	(5.4)	(5.0)	(16.0)	(14.5)
Historical cost depreciation adjustments	—	—	(0.1)	(0.1)
	(5.1)	(5.5)	(16.9)	(16.5)
Net income (loss) allocable to common and i-units	$(19.5)	$22.1	$ 22.6	$ 80.1
Weighted average units outstanding	62.1	55.7	61.5	55.1
Net income (loss) per common and i-unit (basic and diluted)	$(0.32)	$0.39	$ 0.37	$ 1.45

4. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), if a derivative financial instrument does not qualify as a hedge or is not designated as a hedge, a change in the fair market value, both realized and unrealized, is recognized currently in our income statement as a derivative fair value gain (loss) and recorded in Cost of natural gas. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to/from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the future physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Accumulated other comprehensive income ("OCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas in the period the hedged transaction occurs. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these financial instruments are considered 'non-qualified' under SFAS No. 133. These non-qualified derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. **Transportation—**In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. **Storage—**In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast. This can occur because we have the flexibility to make these changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation established at the inception of the hedge.

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship and contemporaneously re-designated the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices, which was a sound economic hedging strategy. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the financial side of the transaction is recorded at fair market values while the physical side of the transaction is not) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Discontinuance of Hedge Accounting

During the second quarter of 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery points for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, during the second quarter of 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of Income from OCI. Going forward, the discontinued derivative financial instruments are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed out during the second quarter.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended September 30, 2005	Three months ended September 30, 2004	Nine months ended September 30, 2005	Nine months ended September 30, 2004
	(in millions)			
Natural Gas segment				
Ineffectiveness	$ 0.1	$ —	$ (1.9)	$ —
Non-qualified hedges	(9.6)	—	(20.7)	—
Marketing				
Non-qualified hedges	(43.1)	0.3	(37.8)	(1.4)
Discontinuance	—	—	(9.0)	—
Derivative fair value gains (losses)	$(52.6)	$0.3	$(69.4)	$(1.4)

We record the change in fair value of our highly effective cash flow hedges in our OCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. For the three and nine months ended September 30, 2005, we reclassified unrealized losses of $11.5 million and $36.7 million from OCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	September 30, 2005	December 31, 2004
	(in millions)	
Receivables, trade and other	$ 16.2	$ 8.2
Other assets, net	7.0	10.1
Accounts payable and other	(177.9)	(45.9)
Other long-term liabilities	(264.4)	(99.6)
	$(419.1)	$(127.2)

The increase in our obligation associated with our derivative activities from December 31, 2004 to September 30, 2005 is primarily due to the significant increases in forward natural gas and NGL prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price sales agreements.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated “A” or better by the major credit rating agencies.

5. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $29.8 million at September 30, 2005 and $25.3 million at December 31, 2004, are included in Accounts payable and other on the Consolidated Statements of Financial Position.

6. PROPERTY, PLANT AND EQUIPMENT

Based on a third-party study commissioned by management, revised depreciation rates for the Anadarko, North Texas and East Texas systems were implemented effective August 1, 2005. The annual composite rate, which represents the expected remaining service life of these natural gas systems, was reduced from 4.0% to 3.4%. Depreciation expense for the three and nine months ended September 30, 2005 was approximately $1.0 million lower as a result of the new depreciation rates.

7. DEBT

Amendments to Credit Agreement

In April 2005, we entered into the third amendment to the Amended and Restated Credit Agreement dated as of January 24, 2003 (as amended, the “Credit Facility”) to, among other things, extend the maturity of the Credit Facility for a period of five years to April 2010; increase the letter of credit sub limit from $100 million to $175 million; and grant us the right to request, subject to approval by the Board of Directors of Enbridge Energy Management, L.L.C. (“Enbridge Management”), an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion.

In September 2005, we entered into the fourth amendment to the Credit Facility to, among other things, extend the letter of credit sub limit from $175 million to $300 million, increase the commitments available under the Credit Facility from $600 million to $800 million, decrease the “Applicable Rate” as set forth in the Credit Facility, and extend from September 2005 to December 31, 2006, the requirement to maintain a Consolidated Leverage Ratio, as defined in the Credit Facility, of not more than 5.25 to 1. At September 30, 2005, we have no outstanding borrowings under the Credit Facility.

Commercial Paper Program

In April 2005, we successfully entered the commercial paper market with the establishment of our $600 million commercial paper program that is supported by our long-term Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. We repaid the entire amount previously outstanding under our Credit Facility with proceeds we obtained from issuing commercial paper under this program. Our Credit Facility remains undrawn and available to support our commercial paper program. Under the terms of our commercial paper program, we can issue up to $600 million of commercial paper. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $200 million. At September 30, 2005, we had outstanding $455.0 million of commercial paper at a weighted average interest rate of 3.84% and outstanding letters of credit totaling $179.6 million. At September 30, 2005, we could issue an additional $145 million under our commercial paper program.

8. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Management through September 30, 2005:

Distribution Declaration Date	Distribution Payment Date	Ex-Distribution Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[1]	Retained from General Partner[2]	Distribution of Cash
				(in millions, except per unit amounts)			
July 28, 2005	August 12, 2005	August 5, 2005	$0.925	$ 64.0	$10.5	$0.2	$ 53.3
April 25, 2005	May 13, 2005	May 4, 2005	0.925	63.8	10.3	0.2	53.3
January 24, 2005	February 14, 2005	February 3, 2005	0.925	61.0	10.1	0.2	50.7
				$188.8	$30.9	$0.6	$157.3

(1) The Partnership has issued 595,146 i-units to Enbridge Management, the sole owner of the Partnership's i-units during 2005 in lieu of cash distributions.

(2) The Partnership retains an amount equal to 2% of the i-unit distribution from the General Partner in respect of its 2% general partner interest.

Common unit offering

On February 11, 2005, we issued 2,506,500 Class A common units at $49.875 per unit, which generated proceeds of approximately $124.8 million, net of offering expenses. Additionally, the General Partner contributed $2.7 million to us to maintain its 2% general partner interest in the Partnership. We used the proceeds from this offering to repay amounts outstanding under our Credit Facility.

9. COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact on the environment of our pipeline operations.

As of September 30, 2005 and December 31, 2004, we have recorded $4.2 million and $3.6 million in current liabilities and $5.4 million and $5.3 million in long-term liabilities, respectively, primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain liquids and natural gas assets.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

10. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present certain financial information relating to our business segments:

	As of and for the three months ended September 30, 2005				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$104.1	$1,267.5	$1,162.6	$ —	$2,534.2
Less: Intersegment revenue	—	669.6	55.0	—	724.6
Operating revenue	104.1	597.9	1,107.6	—	1,809.6
Cost of natural gas (Note 4)	—	513.9	1,145.9	—	1,659.8
Operating and administrative	36.1	44.3	1.4	0.6	82.4
Power	19.0	—	—	—	19.0
Depreciation and amortization	18.3	18.1	0.1	—	36.5
Operating income	30.7	21.6	(39.8)	(0.6)	11.9
Interest expense	—	—	—	(28.4)	(28.4)
Other income	—	—	—	2.1	2.1
Net income (loss)	$ 30.7	$ 21.6	$ (39.8)	$(26.9)	$ (14.4)
Capital expenditures (excluding acquisitions)	$ 17.3	$ 69.2	$ —	$ 0.7	$ 87.2

	As of and for the three months ended September 30, 2004				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$107.1	$659.0	$659.6	$ —	$1,425.7
Less: Intersegment revenue	—	384.1	36.8	—	420.9
Operating revenue	107.1	274.9	622.8	—	1,004.8
Cost of natural gas (Note 4)	—	204.2	620.3	—	824.5
Operating and administrative	32.0	33.3	0.8	1.2	67.3
Power	19.7	—	—	—	19.7
Depreciation and amortization	17.6	14.0	—	0.1	31.7
Operating income	37.8	23.4	1.7	(1.3)	61.6
Interest expense	—	—	—	(22.2)	(22.2)
Rate refunds	—	—	—	(12.0)	(12.0)
Other income	—	—	—	0.2	0.2
Net income	$ 37.8	$ 23.4	$ 1.7	$(35.3)	$ 27.6
Capital expenditures (excluding acquisitions)	$ 29.8	$ 71.8	$ —	$ 2.2	$ 103.8

	As of and for the nine months ended September 30, 2005				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$ 303.1	$3,180.1	$2,658.5	$ —	$6,141.7
Less: Intersegment revenue	—	1,635.3	114.0	—	1,749.3
Operating revenue	303.1	1,544.8	2,544.5	—	4,392.4
Cost of natural gas (Note 4)	—	1,299.9	2,582.5	—	3,882.4
Operating and administrative	105.5	126.3	3.1	2.3	237.2
Power	53.2	—	—	—	53.2
Depreciation and amortization	53.6	49.9	0.4	—	103.9
Operating income	90.8	68.7	(41.5)	(2.3)	115.7
Interest expense	—	—	—	(79.6)	(79.6)
Other income	—	—	—	3.4	3.4
Net income	$ 90.8	$ 68.7	$ (41.5)	$(78.5)	$ 39.5
Total Assets	$1,672.8	$2,239.4	$ 557.4	$ 91.4	$4,561.0
Goodwill	$ —	$ 237.8	$ 20.4	$ —	$ 258.2
Capital expenditures (excluding acquisitions)	$ 52.0	$ 206.5	$ —	$ 3.4	$ 261.9

	As of and for the nine months ended September 30, 2004				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$ 301.5	$1,953.9	$1,921.0	$ —	$4,176.4
Less: Intersegment revenue	—	1,109.4	110.0	—	1,219.4
Operating revenue	301.5	844.5	1,811.0	—	2,957.0
Cost of natural gas (Note 4)	—	639.8	1,804.0	—	2,443.8
Operating and administrative	93.2	99.0	2.4	3.2	197.8
Power	54.0	—	—	—	54.0
Depreciation and amortization	50.5	38.6	—	0.1	89.2
Operating income	103.8	67.1	4.6	(3.3)	172.2
Interest expense	—	—	—	(65.8)	(65.8)
Rate refunds	—	—	—	(12.0)	(12.0)
Other income	—	—	—	2.2	2.2
Net income	$ 103.8	$ 67.1	$ 4.6	$(78.9)	$ 96.6
Total assets	$1,665.8	$1,653.0	$ 252.7	$ 29.5	$3,601.0
Goodwill	$ —	$ 236.6	$ 20.4	$ —	$ 257.0
Capital expenditures (excluding acquisitions)	$ 56.6	$ 114.5	$ —	$ 3.5	$ 174.6

11. SUBSEQUENT EVENTS

Distribution to Partners

On October 26, 2005, Enbridge Management's Board of Directors declared a distribution payable to our partners on November 14, 2005. The distribution will be paid to unitholders of record as of November 3, 2005, of our available cash of $64.1 million at September 30, 2005, or $0.925 per common unit. Of this distribution, $53.3 million will be paid in cash, $10.6 million will be distributed in i-units to our i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

Gathering and Processing Asset Sale

On October 20, 2005, we entered into agreements to sell a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems for $106.0 million. The facilities represent non-strategic assets within our Natural Gas segment and are not in our core geographic areas of interest. We intend to use the proceeds from this sale to finance other projects in our core geographic areas of interest.

12. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting for Conditional Asset Retirement Obligations

In March 2005, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*. This interpretation clarifies the meaning of "conditional asset retirement obligation" as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, as referring to a legal obligation to perform an asset retirement activity where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of an entity. The obligation to perform the retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement. The interpretation requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. We are currently evaluating the effect that application of this interpretation will have on our financial statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3*. Under this statement, voluntary changes in accounting principle are required to be applied retrospectively for the direct effects of a change to prior periods' financial statements, unless such application is impracticable. Retrospective application refers to reflecting a change in accounting principle in the financial statements of prior periods as if the principle had always been used. When retrospective application is determined to be impracticable, this statement requires the new accounting principle to be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective treatment is practicable with a corresponding adjustment to the opening balance of retained earnings. This statement retains the guidance in APB Opinion No. 20 for reporting the corrections of errors and changes in accounting estimates. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, with early adoption permitted. Our adoption of this statement will affect our consolidated financial statements for any changes in accounting principle we may make in the future, or new pronouncements we adopt that do not provide transition provisions.

FERC Guidance on Accounting for Integrity Management Costs

In June 2005, the Federal Energy Regulatory Commission ("FERC") issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance is effective January 1, 2006, to be applied prospectively. We are currently evaluating the effect that application of this order will have on our financial statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and provide returns for our unitholders primarily through the following activities:

- Interstate transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transmission of natural gas; and
- Providing supply, transmission and sales services, including purchasing and selling natural gas and natural gas liquids ("NGLs").

We primarily provide fee-based services to our customers to minimize commodity price risks. However, in our natural gas and marketing businesses, a portion of our earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure and to provide stability to the Partnership's cash flow, we enter into derivative financial instrument transactions. Certain of these transactions qualify for hedge accounting under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"); some however, must be accounted for using the mark-to-market method of accounting and this can expose our earnings to significant volatility.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects operating income by business segment and corporate charges for each of the periods presented.

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating Income				
Liquids	$ 30.7	$ 37.8	$ 90.8	$103.8
Natural Gas	21.6	23.4	68.7	67.1
Marketing	(39.8)	1.7	(41.5)	4.6
Corporate, operating and administrative	(0.6)	(1.3)	(2.3)	(3.3)
Total Operating Income	11.9	61.6	115.7	172.2
Interest expense	(28.4)	(22.2)	(79.6)	(65.8)
Rate refunds	—	(12.0)	—	(12.0)
Other income	2.1	0.2	3.4	2.2
Net Income (Loss)	$(14.4)	$ 27.6	$ 39.5	$ 96.6

Our results for our Natural Gas and Marketing businesses for the three and nine months ended September 30, 2005, were adversely affected by significant non-cash volatility associated with our portfolio of derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. Under SFAS No. 133, all financial instruments are recorded in the consolidated financial statements at fair market value. For those financial instruments that do not qualify for hedge accounting, all changes in fair market value are recorded through the Consolidated Statements of Income each period. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, although that is not our intent.

A volatile natural gas and NGL pricing environment during the three and nine months ended September 30, 2005, produced non-cash mark-to-market losses of $52.6 million and $67.3 million, respectively, and negatively affected our results. While these mark-to-market losses create volatility in our results, they do not affect our cash flow. We expect to offset these non-cash losses in future quarters as we settle the derivative financial instruments and the underlying physical transactions.

The following table presents the unrealized, non-cash, mark-to-market gains and losses by segment, associated with our derivative financial instruments for the three and nine month periods ended September 30, 2005 and 2004:

Derivative fair value gains (losses)	Three months ended September 30, 2005	Three months ended September 30, 2004	Nine months ended September 30, 2005	Nine months ended September 30, 2004
	(in millions)			
Natural Gas segment				
Ineffectiveness	$ 0.1	$ —	$ (1.9)	$ —
Non-qualified hedges	(9.6)	—	(20.7)	—
Marketing				
Non-qualified hedges	(43.1)	0.3	(37.8)	(1.4)
Discontinuance	—	—	(9.0)	—
Derivative fair value loss	$(52.6)	$0.3	$(69.4)	$(1.4)

Average daily volumes of our Natural Gas operations for the three and nine months ended September 30, 2005, were up 17 percent and 20 percent, respectively over the comparable periods in 2004. The increase in volumes is attributable to historically high natural gas and NGL prices, which encourage producers to generate greater volumes of natural gas and NGL. Additionally, during the quarter we benefited from completion of the construction of our East Texas expansion project which was placed in service late in the second quarter of 2005, and partially alleviated physical pipeline constraints being experienced by our Natural Gas and Marketing segments. The favorable effect of these higher volumes was offset by continued lower transportation volumes in our Liquids segment and non-cash mark-to-market losses related to our derivative transactions that do not qualify for hedge accounting treatment under SFAS No. 133.

During the third quarter of 2005, we sustained minor damage to our on- and offshore natural gas gathering and processing facilities as a result of hurricanes Katrina and Rita. Our facilities in Mississippi and Louisiana sustained physical damage, including a CO_2 processing plant, four tractor vehicles used to transport bulk liquid trailers, several compressor stations and on-site offices, in addition to electrical equipment and process controls that were damaged due to flooding. Certain of our other natural gas gathering and processing systems were indirectly affected by third-party facility disruptions resulting from the storms. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants. However, we were able to substantially mitigate the impact of extensive gathering and processing system shutdowns by arranging for NGLs to be transported from our plants by truck and by working with the interconnecting natural gas pipelines to manage natural gas quality at major receipt points. Although we continue to assess the damage caused by these two hurricanes, we do not expect the effect on net income to be more than $5 million during 2005, including lost revenue less cost of natural gas resulting from system downtime and repairs. We do not anticipate recovery of any significant amounts from insurance for these losses. We expect that a majority of our facilities will return to normal operation before year end.

In January 2005, we acquired natural gas gathering and processing assets in North Texas. The facilities acquired include approximately 2,200 miles of natural gas gathering pipelines and four natural gas processing plants with an aggregate processing capacity of 121 million cubic feet per day (“MMcf/d”) of natural gas. This system predominantly serves producers in the Fort Worth Basin Conglomerate formation and is located in an area where we expect future drilling by producers extending the Barnett Shale play's western side. We combined these assets with our existing North Texas assets and have included them in the operating results of our Natural Gas segment from the date of acquisition. In late June 2005, we also acquired an idle 92-mile natural gas pipeline that extends from the Texas Panhandle to Western Oklahoma which we integrated with our existing Anadarko system. We expect this pipeline to improve service to existing customers and allow us to attract additional production in future periods. We have also acquired other small pipelines that are complementary to our existing natural gas assets.

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating Results				
Operating revenues	$104.1	$107.1	$ 303.1	$ 301.5
Operating and administrative	(36.1)	(32.0)	(105.5)	(93.2)
Power	(19.0)	(19.7)	(53.2)	(54.0)
Depreciation and amortization	(18.3)	(17.6)	(53.6)	(50.5)
Operating expenses	(73.4)	(69.3)	(212.3)	(197.7)
Operating Income	$ 30.7	$ 37.8	$ 90.8	$ 103.8
Operating Statistics				
Lakehead system:				
United States[(1)]	1,007	1,063	1,023	1,060
Province of Ontario[(1)]	283	331	295	359
Total deliveries[(1)]	1,290	1,394	1,318	1,419
Barrel miles (billions)	82	92	249	274
Average haul (miles)	691	715	691	705
Mid-Continent system deliveries[(1)]	259	264	225	236
North Dakota system deliveries[(1)]	84	85	87	81

(1) Average barrels per day ("Bpd") in thousands.

Three months ended September 30, 2005 compared with three months ended September 30, 2004

Our Liquids segment accounted for $30.7 million of operating income during the three months ended September 30, 2005, representing a decrease of $7.1 million over the same period in 2004. Lower results on the Lakehead and Mid-Continent systems were slightly offset by stronger results on the North Dakota system.

Operating revenue for the third quarter of 2005 decreased by approximately $3.0 million to $104.1 million from $107.1 million for the same period in 2004. Overall tariff increases and longer hauls on our North Dakota system were more than offset by lower deliveries on our Lakehead system.

Increases in average tariffs on all three Liquids systems resulted in higher operating revenue by approximately $3.4 million. These tariff increases were mostly the result of the annual index rate increase of approximately 3.63% allowed by the Federal Energy Regulatory Commission ("FERC") effective July 1, 2005, on our base system tariffs. On the Lakehead system, new tariffs also went into effect on April 1, 2005 for an adjustment on the Terrace expansion program surcharge due to lower than expected volumes moving on the Lakehead system, and new facilities in service, which were not in effect during the third quarter of 2004. Longer hauls on our North Dakota system also contributed to a higher average tariff, as production in Montana continues to be strong during the third quarter of 2005.

Volumes on the Lakehead system decreased approximately 7%, from 1.394 million Bpd during the third quarter of 2004 to 1.290 million Bpd during the same period in 2005. This resulted in lower operating revenue of approximately $6.4 million. The decrease is the result of lower than expected crude oil supply in Western Canada from two sources. First, Suncor, an oil sands producer in Alberta, Canada, had a fire at their upgrader site on January 4, 2005. Since that time, their production has been reduced by an average of 89,000 Bpd during 2005. In late September, Suncor announced that repairs to the upgrader site and an expansion were completed and production capacity has increased as a result. As a result, we expect deliveries on the Lakehead system to increase in the fourth quarter 2005. Western Canadian crude oil supply available for delivery on our Lakehead system was also reduced due to lower bitumen supplies. The nature of the cyclic steaming process used to extract bitumen from the ground can cause production timing differences during the year. Finally, during the second quarter of 2005, Terasen Inc. completed an expansion on its Express Pipeline, which transports western Canadian crude to the U.S. Rocky Mountain market. This expansion increased capacity on this pipeline by approximately 108,000 Bpd. Given the volume commitments on the Express Pipeline expansion, coupled with the lower western Canadian crude oil supply as noted above, deliveries on our Lakehead system were negatively impacted during the third quarter of 2005. We believe that holders of firm capacity on the Express Pipeline will first satisfy their commitments to that pipeline before moving incremental barrels on the Lakehead system.

Operating and administrative expenses for the Liquids segment increased $4.1 million or 13% in the third quarter of 2005, compared with the same period in 2004. The increase is driven primarily from higher workforce related costs of approximately $2.2 million, and lower capital project recoveries by approximately $1.0 million due to a decrease in utilization of our workforce on capital projects and a reduction in construction activity on our Lakehead system.

Nine months ended September 30, 2005 compared with nine months ended September 30, 2004

Our Liquids segment accounted for $90.8 million of operating income, representing a decrease of $13.0 million from the same period in 2004. Lower results on the Lakehead system were modestly offset by stronger results on our North Dakota system and a full nine-month contribution from our Mid-Continent system compared with a seven-month contribution for the same period in 2004.

Operating revenue for the first nine months of 2005 increased by $1.6 million to $303.1 million, compared with $301.5 million for the same period in 2004. The increase in average tariffs on our Liquids systems resulted in higher operating revenue of approximately $10.5 million for the reasons noted above in the three-month analysis. Our Mid-Continent assets contributed higher operating revenue of approximately $6.3 million for the additional two months of ownership in 2005 compared with 2004. These increases were mostly offset by lower deliveries on the Lakehead system for the same reason as noted above in the three-month analysis, which resulted in a decrease of approximately $18.0 million in operating revenue in the nine-month period.

Operating and administrative expenses for the first nine months of 2005 increased by $12.3 million to $105.5 million, compared with $93.2 million for the same period in 2004. The increase is driven primarily by higher oil measurement losses of approximately $7.0 million and workforce related costs of approximately $4.5 million on the Lakehead system for the nine-month period.

Oil measurement losses occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation losses, which are a function of crude oil prices, the level of the carrier's inventory and the inventory positions of customers.

During the nine months ended September 30, 2005, the increase in oil measurement losses was a function of three factors:

1. Higher volumetric physical losses associated with changes in commodity properties and measurement, coupled with higher oil prices that made the monetary value of normal physical losses more expensive. During the first nine months of 2005, the average West Texas Intermediate crude oil price was approximately $55 per barrel compared with approximately $39 per barrel during the same period in 2004;
2. Wider light/heavy crude price differentials made degradation losses more expensive. During the first nine months of 2005, light/heavy differentials were approximately $20 per barrel compared with approximately $11 per barrel in 2004; and
3. Limited market liquidity is available to settle specific crude oil positions that are naturally created by our pipeline system's operations. Market liquidity is especially constrained when a price trend is anticipated by third-party crude oil marketers. As a result, we carried net short positions that we could not physically settle during the first three months of 2005, on which we experienced a loss prior to settling the position.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and average daily volumes of our major systems in millions of British Thermal units per day ("MMBtu/d") for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 597.9	$ 274.9	$ 1,544.8	$ 844.5
Cost of natural gas	(513.9)	(204.2)	(1,299.9)	(639.8)
Operating and administrative	(44.3)	(33.3)	(126.3)	(99.0)
Depreciation and amortization	(18.1)	(14.0)	(49.9)	(38.6)
Operating expenses	(576.3)	(251.5)	(1,476.1)	(777.4)
Operating Income	$ 21.6	$ 23.4	$ 68.7	$ 67.1
Average Daily Volume (MMBtu/d)				
East Texas	904,000	693,000	841,000	643,000
Anadarko[(1)]	489,000	388,000	473,000	334,000
North Texas	267,000	196,000	264,000	192,000
South Texas	31,000	38,000	34,000	42,000
UTOS	154,000	259,000	181,000	227,000
MidLa	129,000	103,000	113,000	106,000
AlaTenn	42,000	47,000	59,000	60,000
KPC	8,000	20,000	29,000	45,000
Bamagas	110,000	55,000	44,000	33,000
Other major intrastates[(1)]	164,000	167,000	197,000	174,000
Total	2,298,000	1,966,000	2,235,000	1,856,000

(1) Anadarko includes the combined systems previously referred to separately as Anadarko and Palo Duro. The Palo Duro volumes were formerly included with Other major intrastates.

Three months ended September 30, 2005 compared with three months ended September 30, 2004

A portion of our Natural Gas segment is exposed to commodity price risks associated with percent of proceeds or percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time. The remainder of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services.

Our Natural Gas segment contributed $21.6 million of operating income in the third quarter of 2005, representing a decrease of $1.8 million from the $23.4 million of operating income contributed in the corresponding period of 2004. Operating income of our Natural Gas segment for the third quarter of 2005 includes non-cash, mark-to-market net losses of $9.5 million, of which a gain of $0.1 million is due to ineffectiveness on our qualified cash flow hedges and a loss of $9.6 million is attributable to certain derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 (refer also to the discussions included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk). These non-cash losses primarily resulted from the significant increases in forward natural gas and NGL prices during the quarter. The increase in prices reduces the fair market value of these derivative financial instruments because the fixed price component of these derivatives is significantly less than the market price of natural gas at each of the forward settlement points. Although changes in the fair value of these specific derivative financial instruments do not affect our cash flow, we anticipate these changes will continue to create volatility in our Consolidated Statements of Income going forward due to the inherent volatility of natural gas and NGL prices.

A relatively small, but variable element of the Natural Gas segment's operating income is derived from keep-whole processing of natural gas. This contract structure requires us to process natural gas at times when it may not be economical to do so. This can happen when natural gas prices are unusually high or NGL prices are unusually low. During the third quarter of 2005, although natural gas prices were unusually high, they were more than offset by favorable NGL prices. Operating revenue less cost of natural gas derived from keep-whole processing for the three months ended September 30, 2005, was approximately $8.7 million compared with $7.2 million for the same period in 2004.

Average daily volumes on our major natural gas systems increased 17% in the third quarter of 2005, compared with the corresponding period in 2004. The increase in volumes is primarily the result of additional wellhead supply contracts on our East Texas and Anadarko systems, as well as the additional volumes on the North Texas system associated with the gathering and processing assets we acquired in January 2005. Drilling activity continues to increase in the Anadarko Basin, Bossier Trend and Barnett Shale areas. Additionally, completion of the East Texas expansion project in late June 2005 contributed modestly to the growth in volumes for the three months ended September 30, 2005. With continued investment in our systems to expand capacity, we expect our major natural gas systems to benefit from the increase in production volumes expected to result. The increases in volumes on our major natural gas systems were minimally offset by seasonal weather-related decreases on our KPC system and the effect of hurricanes Katrina and Rita on our UTOS and other major intrastate pipelines.

The positive growth in our natural gas and NGL gathering, processing and transportation volumes for the third quarter of 2005 was partially offset by increases in operating costs that are mostly variable with volumes. The higher volumes on the systems resulted in increases of workforce related costs approximating $3.7 million and repair and maintenance costs of approximately $1.0 million. Operating costs were also higher in 2005 by $2.0 million of incremental costs associated with the natural gas gathering and processing assets we acquired in January 2005.

Nine months ended September 30, 2005 compared with nine months ended September 30, 2004

The $68.7 million of operating income generated by our Natural Gas segment during the nine months ended September 30, 2005 includes non-cash, mark-to-market losses of $22.6 million, $1.9 million of which is due to ineffectiveness on our qualified cash flow hedges and $20.7 million of which is attributable to natural gas collars that do not qualify for hedge accounting treatment under SFAS No. 133 (refer also to the discussions included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk). These non-cash losses primarily resulted from the significant increases in forward natural gas and NGL prices as noted previously in our three month analysis.

Operating revenue less cost of natural gas derived from keep-whole processing for the nine months ended September 30, 2005, was approximately $18.7 million compared with $10.2 million for the same period in 2004. The increase was due to the same reasons as previously noted in our three-month analysis.

Average daily volumes on our major natural gas systems increased 20%, or approximately 380,000 MMBtu/d, for the nine months ended September 30, 2005, compared with the corresponding period in 2004. The increase in volumes is consistent with the reasons cited above in our three-month analysis.

Operating and administrative costs associated with our Natural Gas segment were $27.3 million greater for the nine months ended September 30, 2005, than for the same period in 2004. The volume growth on our systems contributed approximately $11.4 million in workforce related costs. Additionally, the natural gas gathering and processing assets we acquired in January 2005 contributed to the cost increases by approximately $5.2 million. The volume growth on our systems, in addition to three processing plants that went down during the nine months ended September 30, 2005, increased maintenance costs by approximately $5.8 million, and also contributed to the increase in materials and supply costs of $1.8 million.

Our depreciation and amortization expense for the nine months ended September 30, 2005 exceeded the amount reported for the same period in 2004 by approximately $11.3 million, primarily as a result of acquisitions and increased capital expenditures. The increase was partially offset by modest extensions of the depreciable lives of our major pipeline systems as a result of a depreciation study completed during the third quarter of 2005.

Marketing

The following table sets forth the operating results for the Marketing segment assets for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating revenues	$ 1,107.6	$ 622.8	$ 2,544.5	$ 1,811.0
Cost of natural gas	(1,145.9)	(620.3)	(2,582.5)	(1,804.0)
Operating and administrative	(1.4)	(0.8)	(3.1)	(2.4)
Depreciation and amortizationn	(0.1)	—	(0.4)	—
Operating expenses	(1,147.4)	(621.1)	(2,586.0)	(1,806.4)
Operating Income (loss)	$ (39.8)	$ 1.7	$ (41.5)	$ 4.6

Three months ended September 30, 2005 compared with three months ended September 30, 2004

A majority of the operating income of our Marketing segment is derived from selling natural gas received from customers on our Natural Gas segment pipeline assets to end users of natural gas. A majority of the natural gas is purchased in Texas markets where we have limited physical access to the primary interstate pipeline delivery points, or hubs such as Waha, Texas and the Houston Ship Channel. As a result, our Marketing business must use third-party pipelines to transport the natural gas to these markets where it can be sold to end users. However, physical pipeline constraints often require our Marketing business to transport natural gas to alternate market points. Under these circumstances, our Marketing segment will sell the purchased gas at a pricing index that is different from the pricing index at which the gas was purchased. This creates a price exposure that arises from the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold, otherwise known as the "spread." The spread can vary significantly due to local supply and demand factors. Wherever possible, this pricing exposure is economically hedged using derivative financial instruments. However, the structure of these economic hedges often precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

To ensure that we have access to primary pipeline delivery points, we often enter into firm transportation agreements on interstate and intrastate pipelines. In order to offset the demand charges associated with these firm transportation contracts, we look for market conditions that allow us to lock in the price differential or spread between the pipeline receipt point and pipeline delivery point. This allows our Marketing business to lock in a fixed sales margin inclusive of pipeline demand charges. We accomplish this by transacting basis swaps between the index where the natural gas is purchased and the index where the natural gas is sold. By transacting a basis swap between those two indices, we can effectively lock in a margin on the combined natural gas purchase and the natural gas sale, mitigating the demand charges on firm transportation agreements and limiting the Partnership's exposure to cash flow volatility that could arise in markets where the firm transportation becomes uneconomic. However, the structure of these transactions precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

In addition to natural gas basis swaps, we contract for storage to assist balancing natural gas supply and end use market sales. In order to mitigate the absolute price differential between the cost of injected natural gas and withdrawn natural gas, as well as storage fees, the injection and withdrawal price differential, or "spread" is hedged by buying fixed price swaps for the forecasted injection periods and selling fixed price swaps for the forecasted withdrawal periods. When the injection and withdrawal spread increases or decreases in value as a result of market price movements, we can earn additional profit through the optimization of those hedges in both the forward and daily markets. Although each of these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact the income statement.

During the quarter ended September 30, 2005, disruptions of natural gas supplies from facilities in the Gulf of Mexico region caused by hurricanes Katrina and Rita created greater demand for natural gas production from our onshore Natural Gas segment pipeline assets, increasing our ability to optimize natural gas supply to areas of strongest demand. As a result of the hurricanes, unusual volatility in the prices of natural gas created greater spreads on our natural gas volumes.

Although our Marketing segment was not adversely affected from the temporary supply disruptions in the Gulf of Mexico, we generally continue to be affected by lower unit margins on natural gas volumes purchased due to physical pipeline constraints. The recent completion of our East Texas system expansion has partially alleviated these constraints; however, increasing production volumes will continue to create additional constraints, which will require continued use of third-party pipelines in East Texas. This situation is not limited to the East Texas region. Pricing in our natural gas supply markets is expected to continue to experience increasing pressure due to a greater supply of natural gas from the Rocky Mountains, Midcontinent and North Texas. For this reason we have increased our commitments on third-party pipelines to provide insurance against pipeline constraints and to provide more attractive market outlets for our natural gas supply. However, there continue to be timing differences between the acquisition of new third-party pipeline capacity and the negotiation of applicable downstream sales agreements. Until new markets are developed, our Marketing segment sells greater portions of its natural gas supply in less attractive short-term markets.

In the third quarter of 2005, our Marketing segment incurred losses of $39.8 million compared with earning $1.7 million of operating income for the corresponding period in 2004. Included in operating loss for the third quarter of 2005 are non-cash, mark-to-market losses of approximately $43.1 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. In the second quarter of 2005, we revised our business strategy for the use of derivative financial instruments associated with the transportation and storage of natural gas to afford us the ability to respond to changing economic conditions. The flexibility provided by the revised strategy precludes us from continuing the use of hedge accounting with regard to these transactions. Under SFAS No. 133, if the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation, the financial instruments must be marked-to-market each period with the change in fair market value recorded in earnings. However, SFAS No. 133 does not allow us to mark-to-market the change in value of the related underlying physical transaction which creates earnings volatility when the "spreads" move. We expect these net mark-to-market losses to be offset when the related physical transactions are settled (refer also to the discussion included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Nine months ended September 30, 2005 compared with nine months ended September 30, 2004

Our Marketing segment incurred an operating loss of $41.5 million for the nine months ended September 30, 2005, compared with $4.6 million of operating income for the corresponding period in 2004. Included in the operating loss for the nine months of 2005 are non-cash mark-to-market losses of approximately $37.8 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and approximately $9.0 million resulting from the discontinuance of hedge accounting for derivative financial instruments associated with forecasted transactions that we determined were not probable of occurring, as noted above in our three-month analysis.

In the second quarter of 2005, we revised our business strategy as discussed above in our three-month analysis. Approximately $2.1 million of the $9.0 million of loss from the discontinuance of hedge accounting will not be recoverable and relates to hedges we closed out during the second quarter. This $2.1 million will be realized as reduced cash flows over an approximate 15-month period into the fourth quarter of 2006. The Partnership will use its best efforts to mitigate or recover economic losses on this portion of the discontinued derivative financial instruments (refer also to the discussion included under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Corporate

Interest expense was $28.4 million and $79.6 million for the three and nine months ended September 30, 2005, respectively, compared with $22.2 million and $65.8 million for the corresponding periods in 2004. The increases are the result of higher debt balances and higher weighted average interest rates of approximately 5.68% and 5.80% during the three and nine months ended September 30, 2005, respectively, compared with approximately 5.29% and 5.61% during the same periods in 2004. Our weighted average debt balances at September 30, 2005, are greater than the amounts at September 30, 2004 due to the gathering and processing assets in North Texas we acquired in January 2005, in addition to the capital expenditures we have made to expand our existing systems to improve the service capabilities of our assets.

Included in our results for the third quarter of 2004 was a charge related to rate refunds payable on our Kansas Pipeline System ("KPC") for $12.0 million associated with rates charged to customers of KPC prior to our ownership. We extinguished this obligation in the first quarter of 2005 and have not incurred any similar rate refunds during the three and nine month periods ended September 30, 2005.

LIQUIDITY AND CAPITAL RESOURCES

We believe that our ability to generate cash flow, in addition to our access to capital resources, is sufficient to meet the demands of our current and future operating growth and investment needs. Our primary cash requirements consist of normal operating expenses, maintenance and expansion capital expenditures, debt service payments, distributions to partners, acquisitions of new assets or businesses, and payments associated with our derivative transactions. Short-term cash requirements, such as operating expenses, maintenance capital expenditures and quarterly distributions to partners, are expected to be funded from our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from operating activities, borrowings under the commercial paper program we established in April 2005, our credit facilities, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

In April 2005, we entered into the third amendment to the Amended and Restated Credit Agreement dated as of January 24, 2003 (as amended, the "Credit Facility") to, among other things, extend the maturity of the Credit Facility for a period of five years to April 2010; increase the letter of credit sub limit from $100 million to $175 million; and grant us the right to request, subject to approval by the Board of Directors of Enbridge Management, L.L.C. ("Enbridge Management"), an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion.

In September 2005, we entered into the fourth amendment to the Credit Facility to, among other things, extend the letter of credit sub limit from $175 million to $300 million, increase the commitments available under the Credit Facility from $600 million to $800 million, decrease the "Applicable Rate" as set forth in the Credit Facility, and extend from September 2005 to December 31, 2006, the requirement to maintain a Consolidated Leverage Ratio, as defined in the Credit Facility, of not more than 5.25 to 1.

Also in April 2005, we successfully entered the commercial paper market with the establishment of our $600 million commercial paper program that is supported by our long-term Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. We have repaid the entire amount previously outstanding under our Credit Facility with proceeds we obtained from issuing commercial paper under this program. Our Credit Facility remains undrawn and available to support our commercial paper program. Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $200 million. At September 30, 2005, we had $455.0 million of commercial paper outstanding at a weighted average interest rate of 3.84%

and outstanding letters of credit totaling $179.6 million. At September 30, 2005, we could issue an additional $145 million under our commercial paper program.

On February 11, 2005, we issued an additional 2,506,500 Class A common units at $49.875 per unit, which generated proceeds, net of offering expenses, of approximately $124.8 million. Additionally, the General Partner contributed $2.7 million to us to maintain its 2% general partner interest in the Partnership. We used the proceeds from this offering to repay borrowings under our Credit Facility.

Working capital, defined as current assets less current liabilities, decreased by $107.5 million to a net liability of $38 million at September 30, 2005, compared with an asset of $69.5 million at December 31, 2004. This decrease was primarily attributable to increases in liabilities associated with the changes in fair value of our derivative financial instruments.

At September 30, 2005, cash and cash equivalents totaled $93.4 million, compared with $78.3 million at December 31, 2004. Of the cash balance, $64.1 million ($0.925 per unit) is available for cash distributions to our unitholders on November 14, 2005. Of this distribution, $53.3 million will be paid in cash, $10.6 million will be distributed in i-units to our i-unitholder and $0.2 million retained from our General Partner in respect of this i-unit distribution.

Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2005 was $208.2 million, compared with $225.9 million for the same period in 2004. The decrease in 2005 was primarily due to general timing differences in the collection on and payment of our related party and current accounts.

Investing Activities

Net cash used in investing activities during the nine months ended September 30, 2005 was $442.3 million, compared with $313.4 million for the same period in 2004. The increase of $128.9 million was partially attributable to greater amounts we expended for the acquisition of the North Texas Gathering system and other natural gas gathering assets in 2005 than the amount we paid for the Mid-Continent and Palo Duro systems acquired in 2004. We acquired gathering and processing assets in north Texas for approximately $164.6 million in January 2005 and other natural gas gathering assets for approximately $21.8 million during the nine months ended September 30, 2005. In addition to our acquisitions, we spent $261.9 million in connection with our core maintenance and system enhancement projects, representing an increase of $87.3 million over the $174.6 million we spent for the same period of 2004. This increase was primarily due to the construction of our East Texas system expansion, which was completed in June 2005, and several smaller projects to expand our existing natural gas transmission and processing capacity as well as crude oil storage facilities. Additional information regarding our capital expenditures is provided below.

Financing Activities

Net cash provided by financing activities during the nine months ended September 30, 2005 was $249.2 million, compared with $117.1 million for the corresponding period in 2004. The increase of $132.1 million in cash flow is primarily due to net borrowings under our commercial paper program and Credit Facility, partially offset by an increase in distributions to our partners. Distributions to our partners were higher in 2005 due to an increase in the number of units outstanding, as well as a related increase in the general partner incentive distributions resulting from the larger number of units outstanding.

CAPITAL EXPENDITURES

We rely upon cash flow from our operating activities and access to the capital markets to provide the funds necessary to execute our growth strategy and complete our projects. Our success with generating and raising capital is a critical factor that determines how much we spend in connection with our growth objectives. We believe our ability to generate or otherwise access the necessary capital resources is sufficient to meet the demands of our current and future operating growth needs. Although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in economic conditions.

We estimate our capital expenditures based on our long range strategic operating and growth plans. These estimates may change due to factors beyond our ability to control including changes in supplier prices, resource constraints and poor economic conditions. Additionally, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or operational considerations.

We categorize capital expenditures as either core maintenance or system enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or approaching the end of their useful lives. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards. We made capital expenditures of approximately $261.9 million, including $23.1 million on core maintenance activities, during the nine months ended September 30, 2005. For the full year 2005, we anticipate capital expenditures to approximate $411 million, as illustrated in the following table:

	(in millions)
System enhancements	$311
Core maintenance activities	36
East Texas expansion	64
	$411

As of September 30, 2005, we have contractual commitments totaling $32.5 million for materials and services related to our organic growth projects. We expect to settle these commitments during the remainder of 2005 and 2006.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to both ensure regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

DERIVATIVE ACTIVITIES

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the purchase and sales prices of our commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments at September 30, 2005 for each of the indicated calendar years:

	Notional	2005	2006	2007	2008	2009	2010	2011	2012
				($ in millions)					
Swaps									
Natural gas[1]	575,618,282	$(29.8)	$ (81.7)	$(47.6)	$(39.9)	$(25.6)	$(20.3)	$(19.5)	$(4.5)
NGL[2]	291,654,468	(21.1)	(39.0)	(30.3)	(7.8)	—	—	—	—
Crude[2]	1,372,169	(2.8)	(9.0)	(8.2)	(5.4)	(1.1)	—	—	—
Options—calls									
Natural gas[1]	6,849,000	(2.5)	(7.4)	(5.2)	(3.9)	(3.1)	(2.5)	(2.6)	—
Options—puts									
Natural gas[1]	7,079,000	—	—	—	—	0.1	0.1	0.2	—
Totals		$(56.2)	$(137.1)	$(91.3)	$(57.0)	$(29.7)	$(22.7)	$(21.9)	$(4.5)

(1) Notional amounts for natural gas are recorded in millions of British thermal units (“MMBtu”).

(2) Notional amounts for NGL and Crude are recorded in Barrels (“Bbl”).

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution Declaration

On October 26, 2005, Enbridge Management’s Board of Directors declared a distribution payable on November 14, 2005. The distribution will be paid to unitholders of record as of November 3, 2005, of our available cash of $64.1 million at September 30, 2005, or $0.925 per common unit. Of this distribution, $53.3 million will be paid in cash, $10.6 million will be distributed in i-units to our i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

Gathering and Processing Asset Sale

On October 20, 2005, we entered into agreements to sell a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems for $106.0 million. The facilities represent non-strategic assets within our Natural Gas segment and are not in our core geographic areas of interest. We intend to use the proceeds from this sale to finance other projects in our core geographic areas of interest. Completion of the sale is subject to normal closing conditions and is expected to occur in the fourth quarter of 2005.

FUTURE PROSPECTS

Business Strategy

During 2005, we have shifted our business strategy towards developing and expanding our existing assets, with less focus on acquisitions. This shift primarily results from two factors. First, acquisition prices have been inflated by increased competition for stable energy assets that we seek for the Partnership. The competition includes several new master limited partnerships and private equity investors. We do not rule out making significant acquisitions in the future; however, while prices remain high, our acquisitions will likely be limited to situations where we have natural advantages to create additional value in the future. Second, over the past few years, we have expanded and diversified our asset base, particularly in our Natural Gas business. As a result, a significant number of internal projects are emerging from the assets in our focus regions, primarily Texas. We anticipate that the combination of strong production profiles of the major basins we serve and increasing natural gas supply from the Rocky Mountains and liquefied natural gas ("LNG") imports will require new market access outside of the traditional Texas market. In addition to our East Texas transmission pipeline that we completed in June 2005, we are focusing on an additional market option for our natural gas customers.

This internal growth in our Natural Gas business, coupled with our Southern Access Program on our Lakehead system (see 'Future Prospects—Liquids'), will lead to significant expenditures of capital over the next several years. A disadvantage of internal growth is that it usually entails carrying the cost of constructing new assets before earning a return on those assets. This will be the case with the Partnership's major expansion commitments over the next few years. Over that period, it may not be prudent to increase the cash distribution rate to unitholders from its current level, assuming no significant acquisitions.

Liquids

Average daily crude oil deliveries on our Lakehead system are expected to decrease by approximately 20,000 Bpd during 2005 to approximately 1.38 million Bpd, from our previous forecast of 1.40 million Bpd. This also represents a year-over-year decrease of approximately 42,000 Bpd, from 2004 deliveries of 1.422 million Bpd. The decrease is primarily attributable to the early January 2005 fire at the Suncor oil sands plant in Alberta, a major producer of crude oil in western Canada. During September 2005, Suncor completed repair work on the damaged portions of its facility. With Suncor's return to full production capacity, along with the completion of an expansion to its oil sands upgrading operation in September 2005, we expect an increase in western Canadian crude oil supply and deliveries on our Lakehead system in the fourth quarter of 2005.

In June 2005, an open season was commenced by the Partnership and Enbridge Inc. ("Enbridge") to confirm shipper support for the Southern Access Mainline Expansion and Extension Program ("Southern Access Program"). The Southern Access Program is designed to facilitate access to new and expanding supplies of crude oil from the western Canadian oil sands by the PADD II region of the United States, the major oil hub at Cushing, and, through interconnecting lines, the Texas Gulf Coast. The main elements of the Southern Access Program are:

Mainline Expansion: The Mainline Expansion consists of up to three separate phases, which in aggregate is designed to provide an additional 400,000 Bpd of crude oil capacity on the Enbridge/Lakehead mainline system from Hardisty, Alberta, to Chicago, Illinois. Aggregate capital costs for the Mainline Expansion are currently estimated to be approximately $900 million, of which approximately $760 million is attributable to the U.S. portion of the expansion and will be financed by us. This amount includes cost savings resulting from proceeding concurrently with all three phases of the Mainline Expansion. The balance of the capital costs for the Mainline Expansion is attributable to the Canadian portion of the mainline system and will be financed by Enbridge.

Southern Access Extension: The Southern Access Extension will involve the construction of a new 30-inch diameter pipeline and related facilities designed to transport up to 300,000 Bpd of crude oil from a new interconnection with our Lakehead system, near Chicago, to hubs at Wood River or Patoka, Illinois, or both. The Southern Access Extension will be financed and constructed by Enbridge at an estimated cost of approximately $320 million.

The Partnership and Enbridge expect to recover our costs and earn an annual return of approximately 9%, plus inflation that is amortized over the life of the project, on our equity investment in the U.S. portion of the Southern Access Program. These costs will be collected through a system-wide surcharge on the Lakehead system tolls using a standard cost of service model. The Southern Access Extension will be integrated with our Lakehead system for rate-making purposes.

In July 2005, the Partnership and Enbridge completed the open season in which we solicited and obtained from shippers non-binding indications of support for the construction of all phases of the Southern Access Program. The open season results were supportive of the entire program. For the Mainline Expansion portion of the program, although offered in stages, the shippers indicated interest in proceeding with all three phases concurrently to ensure adequate pipeline capacity. Discussions with shippers are proceeding with the objective of filing agreed tolling principles with the FERC and undertaking preliminary construction preparations this year. For the Southern Access Extension, there was significant support and interest to warrant continued discussion with shippers on project timing and terms of binding commitments. The Southern Access Expansion Program is expected to be in full service in the first quarter of 2009.

A proposal that could compete with our Southern Access Program was announced on October 14, 2005, by Altex Energy Ltd., which proposed a crude oil pipeline from northern Alberta directly to the U.S. Gulf Coast. This concept is subject to shipper support and regulatory approval. The Partnership and Enbridge believe that our Southern Access Program, together with initiatives by Enbridge to provide access to new markets in the Midwest, Midcontinent and Gulf Coast, offer more flexible solutions to future transportation requirements of western Canadian crude oil producers, and the in-service timing of these solutions is much more in line with prospective shipper needs.

In June 2005, Enbridge acquired the remaining 10% stake in the Spearhead Pipeline, giving it 100% ownership in the pipeline, which runs from Cushing, Oklahoma to Chicago. After a successful open season in the fall of 2004, Enbridge is currently in the process of reversing the flow of the Spearhead Pipeline so that it will provide capacity to deliver 125,000 Bpd into the major oil hub at Cushing by 2006. This line could subsequently be expanded to accommodate up to 160,000 Bpd. The FERC approved the application for Spearhead transportation tariffs on March 3, 2005. A portion of the Spearhead Pipeline's revenue requirement will be rolled into Enbridge's Canadian mainline tariffs, which were approved in the second quarter of 2005 by Canada's National Energy Board ("NEB"). The NEB decision has been appealed by one intervener based on jurisdictional grounds and an appeal has been granted by Canada's Federal Court of Appeal. Enbridge expects that this appeal will not be successful and, therefore, is proceeding with the reversal project. We expect to benefit following the reversal, as western Canadian crude oil will be carried on the Lakehead system as far as Chicago, and then transferred to the Spearhead Pipeline to continue to this new market.

During 2004, ExxonMobil Pipeline Company ("ExxonMobil") approached the Canadian Association of Petroleum Producers and prospective shippers with a proposal to reverse the direction of flow on its Beaumont, Texas to Corsicana, Texas and its Corsicana to Patoka pipelines. The combined reversed pipeline will be linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka. The Mustang Pipe Line Partners system is 30% owned by an affiliate of Enbridge. ExxonMobil completed a successful open season with commitments of 50,000 Bpd, and has stated that it will proceed with the reversal, with plans to be in-service by the end of 2005. The reversed pipeline is expected to transport 65,000 Bpd of western Canadian heavy crude to the refinery market located in Beaumont on the U.S. Gulf Coast. The connection of the Lakehead system with this new market should also support increased throughput on the Lakehead system. This has been evidenced by the results of an open season conducted by Mustang Pipeline Partners, which resulted in commitments for higher volumes for transportation from the Lakehead system to Patoka. However, the reversed system will also be capable of transporting western Canadian crude moved via other competing pipelines into Patoka.

Two proposals are currently being pursued to increase pipeline capacity for transportation of crude oil from the oil sands in Alberta to the west coast of Canada, where it could be shipped by tanker to China, other Asia-Pacific markets and California. The Gateway Pipeline is a new 30-inch crude oil pipeline with design capacity of 400,000 Bpd. In April 2005, a memorandum of understanding was entered into between Enbridge and PetroChina International Company Limited to cooperate on the development of the Gateway Pipeline in order to supply approximately 200,000 Bpd of crude oil to China. A regulatory application for the $2.5 billion (Canadian dollars), 720-mile pipeline would have to be made in 2006 to achieve a 2010 in-service date, which is when Enbridge's western Canada crude oil supply forecast indicates that oil sands production will have increased to the level that access to a major new market will be beneficial to producers. Enbridge estimates that between 600,000 and 800,000 Bpd of incremental oil sands production will be available by 2010.

Terasen Inc.'s TMX project is a proposed expansion of its existing Trans Mountain Pipeline system, which runs from Alberta to British Columbia, Canada and Washington State. In July 2005, Terasen Inc. filed an application with the NEB to increase the capacity of its Trans Mountain Pipeline system from 225,000 Bpd to 260,000 Bpd., with a planned in-service date of the first quarter of 2007. This is the first phase of a multi-phased expansion of the Trans Mountain Pipeline. The next phase would include the construction of a 30-inch pipeline loop between Hinton, Alberta and Valemont, British Columbia.

These pipeline expansions are in line with the Partnership's expectations for increased access to new and existing markets for western Canadian crude oil. The Partnership expects the growing supply of crude oil from the Alberta oil sands to exceed the pipeline capacity to current and proposed markets which will require the development of new pipelines out of Western Canada.

Natural Gas

We continue to assess various acquisition and expansion opportunities to pursue our strategy for growth. The market for acquiring energy transportation assets is active and competition among prospective acquirers of assets has been significant. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts on development of our existing pipeline systems. Although one of our objectives is to grow our natural gas business through acquisitions, we may and have pursued opportunities to divest of any non-strategic natural gas assets as conditions warrant.

We completed construction in June 2005 of our new 500 MMcf/d East Texas Expansion Pipeline Project. This new pipeline represents a strategic link between producers both in the Barnett Shale area of North Central Texas and the Bossier/Cotton Valley horizons in East Texas and new markets accessible through the pipeline hub at Carthage, Texas. Carthage access is important to natural gas shippers because it offers a number of pipeline connections which generally provide higher wellhead gas prices for producers. The pipeline is operating within its originally projected capacity with continued increases in utilization expected through the remainder of the year resulting from negotiation of additional commercial arrangements, organic supply growth, and other growth initiatives on our East Texas system.

In addition to the completion of the East Texas Expansion Pipeline Project, we initiated a series of new projects to restart as well as construct certain treating and processing facilities on our East Texas system. We expect to complete these new projects in early 2006 at an estimated cost of approximately $75 million. Completion of these new projects will expand the service offerings we currently provide to our customers on the East Texas system.

Construction on our Anadarko system expansion continues. The first phase of the expansion added 100 MMcf/d of processing capacity which we placed in service in April 2005 and we are proceeding with the second phase of the project to increase the scale of the processing plant to 160 MMcf/d. The total cost of both phases of the project is approximately $52 million and we expect it to be complete by the end of the fourth quarter of 2005. On October 26, 2005, Enbridge Management's Board of Directors approved a project to build a new 125 MMcf/d processing plant to accommodate additional supply growth in this operating area. This facility is expected to be operation in early 2007.

Our Bamagas system has agreements to provide transportation of up to 276,000 MMBtu/d of natural gas for a remaining period of 17 years to two utility plants that are indirectly owned by Calpine Corporation (“Calpine”). The Bamagas system receives a fixed demand charge of $0.07 per MMBtu of natural gas for 200,000 MMBtu/d, regardless of whether the capacity is used. Calpine has recently experienced financial difficulties that it is actively working to alleviate. Although we fully expect our customer to remain solvent and its plants to meet their obligations to us under the terms of the transportation agreements, we are exposed to a potential asset impairment of up to $50 million, representing the book value of the pipeline, should they be unable to fulfill their commitments. We are actively monitoring Calpine’s financial condition and evaluating alternate uses for the system.

As a result of the widespread damage caused by hurricanes Katrina and Rita, the major credit rating agencies have issued negative credit implications for several of our industrial and utility customers. Although we do not anticipate any significant deterioration in the credit standing of these customers, we continue to monitor their financial condition, and expect improvement in their credit standing as system outages are restored and property damage repaired.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

Effective July 1, 2005, in compliance with the indexed rate ceilings allowed by the FERC, the Partnership increased its rates for transportation on the Lakehead, North Dakota and Ozark systems by an average of approximately 3.63%. For the Lakehead system, indexing only applies to its base rates, not the surcharges for the System Expansion Program II (“SEP II”), the Terrace Expansion Program (“Terrace”) and other surcharges. We expect the increase in tariff rates to contribute approximately $5 million to our results of operations for 2005. On the Lakehead system, the new rate for heavy crude movements from the International Border to Chicago is $0.89 per barrel, which reflects an approximate $0.025 cents per barrel increase over rates filed effective April 1, 2005.

Effective April 1, 2005, we filed our annual tariff with the FERC for our Lakehead System. This tariff reflected the annual calculation of the SEP II and other surcharges based on true-ups of prior year amounts and estimates for 2005, and an adjustment for the Terrace surcharge as a result of lower than expected volumes moving on the Lakehead system. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.035 per barrel, to approximately $0.865 per barrel.

FERC Policy on Income Tax Allowances

On May 4, 2005, the FERC adopted a policy to permit cost-of-service rates to reflect an actual or potential income tax liability for all public utility assets, regardless of the form of ownership. The policy statement stems from an opinion issued by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast Products, LLC v. FERC* that remanded the FERC’s decisions on tax allowance treatment in an oil pipeline rate proceeding involving SFPP, L.P., an unrelated pipeline company.

Under the policy, all entities or individuals owning public utility assets would be permitted an income tax allowance on the income from those assets, provided that they have an actual or potential income tax liability on that public utility income. As a result, a taxpaying corporation, partnership, limited liability corporation, or other pass-through entity would be permitted an income tax allowance on the income imputed to the corporation, or to the partners or the members of pass-through entities. Any pass-through entity seeking an income tax allowance in a specific rate proceeding will be required to establish that its partners or members have an actual or potential income tax obligation on the entity’s public utility income. Management is evaluating the new FERC policy. At this time we do not believe the adoption of this policy by the FERC will have a material effect on our financial position, results of operations or cash flows.

FERC Guidance on Accounting for Integrity Management Costs

In June 2005, the FERC issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance is effective January 1, 2006, to be applied prospectively. We are currently evaluating the effect that application of this order will have on our financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2004, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provide information about our derivative financial instruments at September 30, 2005 and December 31, 2004, with respect to our commodity price risk management activities for natural gas and NGLs, including crude:

	At September 30, 2005						At December 31, 2004	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	**Notional[1]**	**Receive**	**Pay**	**Asset**	**Liability**	**Asset**	**Liability**
Contracts maturing in 2005								
Swaps								
Receive variable /pay fixed	Natural Gas	50,900,877	$12.99	$ 6.96	$305.4	$ —	$ 8.1	$(54.5)
Receive fixed /pay variable	Natural Gas	52,529,055	6.99	13.36	—	(333.1)	48.3	(25.9)
	NGL	42,534,912	0.65	1.15	—	(21.1)	1.0	(8.0)
	Crude	86,940	34.41	66.40	—	(2.8)	—	(3.2)
Receive variable /pay variable	Natural Gas	6,068,630	12.69	13.03	1.0	(3.1)	0.7	(2.4)
Options								
Calls (written)	Natural Gas	276,000	13.78	4.74	—	(2.5)	—	(1.7)
Puts	Natural Gas	506,000	13.92	4.13	—	—	0.1	—
Contracts maturing in 2006								
Swaps								
Receive variable /pay fixed	Natural Gas	139,182,126	11.24	7.00	574.8	—	4.2	(7.8)
Receive fixed /pay variable	Natural Gas	145,903,926	6.95	11.57	—	(655.9)	7.8	(23.3)
	NGL	109,318,230	0.68	1.05	—	(39.0)	0.5	(4.1)
	Crude	417,725	44.58	66.81	—	(9.0)	0.4	(1.4)
Receive variable /pay variable	Natural Gas	4,625,281	11.53	11.64	0.9	(1.5)	—	(0.2)
Options								
Calls (written)	Natural Gas	1,095,000	11.70	4.74	—	(7.4)	—	(1.8)
Puts	Natural Gas	1,095,000	11.70	3.40	—	—	—	—
Contracts maturing in 2007								
Swaps								
Receive variable /pay fixed	Natural Gas	49,839,298	9.40	7.20	102.2	—	0.6	(8.2)
Receive fixed /pay variable	Natural Gas	56,856,016	6.94	9.78	—	(150.2)	8.5	(15.8)
	NGL	109,164,930	0.66	0.96	—	(30.3)	0.4	(4.0)
	Crude	388,680	42.05	64.85	—	(8.2)	0.2	(1.3)
Receive variable /pay variable	Natural Gas	2,769,000	9.37	9.23	0.4	—	—	—
Options								
Calls (written)	Natural Gas	1,095,000	9.81	4.74	—	(5.2)	—	(1.5)
Puts	Natural Gas	1,095,000	9.81	3.40	—	—	—	—

	At September 30, 2005						At December 31, 2004	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2008								
Swaps								
Receive variable /pay fixed	Natural Gas	10,236,065	8.35	7.23	10.3	—	—	(1.9)
Receive fixed /pay variable	Natural Gas	21,922,508	6.17	8.81	—	(51.3)	2.3	(12.2)
	NGL	30,636,396	0.61	0.90	—	(7.8)	0.7	(0.2)
	Crude	323,699	44.18	63.03	—	(5.4)	0.5	—
Receive variable /pay variable	Natural Gas	3,294,000	8.20	7.83	1.1	—	—	—
Options								
Calls (written)	Natural Gas	1,098,000	8.62	4.74	—	(3.9)	—	(1.2)
Puts	Natural Gas	1,098,000	8.62	3.40	—	—	0.1	—
Contracts maturing in 2009								
Swaps								
Receive fixed /pay variable	Natural Gas	11,497,500	5.02	7.74	—	(26.4)	—	(9.8)
	Crude	155,125	53.13	61.76	—	(1.1)	—	—
Receive variable /pay variable	Natural Gas	4,197,500	7.32	7.10	0.8	—	—	—
Options								
Calls (written)	Natural Gas	1,095,000	7.74	4.74	—	(3.1)	—	(1.1)
Puts	Natural Gas	1,095,000	7.74	3.40	0.1	—	0.2	—
Contracts maturing after 2009								
Swaps								
Receive fixed /pay variable	Natural Gas	15,796,500	3.63	7.22	—	(44.3)	—	(18.3)
Options								
Calls (written)	Natural Gas	2,190,000	7.12	4.74	—	(5.1)	—	(2.0)
Puts	Natural Gas	2,190,000	7.12	3.40	$ 0.3	—	0.5	—

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at September 30, 2005 and December 31, 2004, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), if a derivative financial instrument does not qualify as a hedge or is not designated as a hedge, a change in the fair market value, both realized and unrealized, is recognized currently in our income statement as a derivative fair value gain (loss) and recorded in Cost of natural gas. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to/from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the future physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Accumulated other comprehensive income ("OCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas in the period the hedged transaction occurs. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these financial instruments are considered 'non-qualified' under SFAS No. 133. These non-qualified derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. **Transportation**—In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of

derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. **Storage—**In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast. This can occur as we have the flexibility to make these changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation established at the inception of the hedge.

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship and contemporaneously re-designated the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices, which was a sound economic hedging strategy. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the financial side of the transaction is recorded at fair market values while the physical side of the transaction is not) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Discontinuance of Hedge Accounting

During the second quarter of 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery points for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133, is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, during the second quarter of 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of Income from OCI. Going forward, the discontinued derivative financial instruments are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also, included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses relating to hedge positions that were closed out during the second quarter.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended September 30, 2005	Three months ended September 30, 2004	Nine months ended September 30, 2005	Nine months ended September 30, 2004
	(in millions)			
Natural Gas segment				
Ineffectiveness	$ 0.1	$ —	$ (1.9)	$ —
Non-qualified hedges	(9.6)	—	(20.7)	—
Marketing				
Non-qualified hedges	(43.1)	0.3	(37.8)	(1.4)
Discontinuance	—	—	(9.0)	—
Derivative fair value gains (losses)	$(52.6)	$0.3	$(69.4)	$(1.4)

We record the change in fair value of our highly effective cash flow hedges in our OCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. For the three and nine months ended September 30, 2005, we reclassified unrealized losses of $11.5 million and $36.7 million from OCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	September 30, 2005	December 31, 2004
	(in millions)	
Receivables, trade and other	$ 16.2	$ 8.2
Other assets, net	7.0	10.1
Accounts payable and other	(177.9)	(45.9)
Other long-term liabilities	(264.4)	(99.6)
	$(419.1)	$(127.2)

The increase in our obligation associated with our derivative activities from December 31, 2004 to September 30, 2005 is primarily due to the significant increases in forward natural gas and NGL prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price sales agreements.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated "A" or better by the major credit rating agencies.

Item 4. Controls and Procedures

The Partnership and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Our management has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2005. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. No changes in our internal control over financial reporting were made during the three months ended September 30, 2005, that would materially affect our internal control over financial reporting, nor were any corrective actions with respect to significant deficiencies or material weaknesses necessary subsequent to that date.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 9, which is incorporated herein by reference.

Item 5. Other Information

The Partnership has adopted a set of Corporate Governance Guidelines, which affirm our commitment to maintaining a high standard of corporate governance. The guidelines are applicable to all of our employees, officers and directors. A copy of the Corporate Governance Guidelines are available on our website at www.enbridgepartners.com. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

Item 6. Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a previous filing as indicated.

3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Third Amended and Restated Agreement of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
10.1	Fourth Amendment to the Amended and Restated Credit Agreement, dated January 24, 2003 (as amended by the First Amendment, dated January 12, 2004, the Second Amendment, dated April 26, 2004, and the Third Amendment dated April 14, 2005), by and among the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on September 21, 2005).
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: October 28, 2005

By: /s/ DAN C. TUTCHER
Dan C. Tutcher
President and Director
(Principal Executive Officer)

Date October 28, 2005

By: /s/ MARK A. MAKI
Mark A. Maki
Vice President, Finance
(Principal Financial Officer)